Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector

R.06-04-009 and D.07-OIIP-01

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Executive Summary

In this proceeding, the California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) are making joint recommendations to the Air Resource Board (ARB) on the greenhouse gas (GHG) strategies best suited to the electricity and natural gas sectors. On March 12th and 13th the joint agencies adopted an Interim Opinion on the type and point of regulation and complementary principles and policies for implementing AB 32.

The Interim Opinion also recommends that energy efficiency and renewables should be the foundation of any regulatory approach for the electricity sector and will account for the majority of GHG reductions. The Energy Commission and the Public Utilities Commission base that recommendation on technical and economic analysis of the social and financial benefits of these strategies. Both the Energy Commission and the Public Utilities Commission are aggressively pursuing energy efficiency and renewable energy through building and appliance standards, utility-delivered programs, and research activities.

One current effort in the joint proceeding, which has led to this staff paper, is the development of recommendations on the preferred approach to the allocation or auctioning of allowances, should ARB decide that there will be a cap and trade program in California that includes the electricity sector. As noted in the Interim Opinion, selection of a point of regulation does not predetermine the approach to allowance allocation. That decision adopts some general principles for allowance allocation but does not resolve other allowance allocation issues. Public workshops will be held at the Public Utilities Commission in San Francisco on April 21 and 22, 2008 for the purpose of discussing this paper and modeling work. Interested parties will be asked to file comments in May which will assist the Public Utilities Commission and the Energy Commission with developing recommendations to the ARB.

This paper is responsive to the Commissions' direction in the Interim Opinion on GHG regulatory strategies (CEC-100-2008-002-F and Public Utilities Commission Decision (D.) 08-03-018) to develop the record further regarding possible approaches to the allocation of GHG emission allowances. This includes options for administrative allocations and auctions, differing bases for allocating allowances or auction revenue rights for that portion of allowances which are auctioned, and the extent to which the allocation method should change over time. The criteria used for evaluating options are based on the Interim Opinion's direction that allocation policy should ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers.

Reviewers of this paper should note that the Commissions are undertaking a number of policy and programmatic efforts to address emissions reductions in the electricity and natural gas sectors. The joint Commission proceeding in which this paper is being released represents only one of several dozen venues in which issues related to AB 32 reductions are being addressed. For example, in separate venues, the Commissions are undertaking rulemakings on more aggressive building codes and appliance standards, big/bold energy efficiency programs for investor-owned utilities, statewide coordination of energy efficiency goals and strategic demand-side planning, renewable portfolio standard implementation, the California Solar Initiative, policies for combined heat and power facilities, and a host of other smaller programs and policies designed to produce GHG emission reductions in these sectors. While the bulk of the current proceeding is focused primarily on the best approach for implementing a market-based mechanism to provide additional GHG reductions beyond mandatory programmatic reductions, this proceeding should not be mistaken for the only or even the main initiative at the two Commissions related to AB 32 goals.

Staff was requested to initiate this portion of the proceeding by developing "staff proposals" or recommendations in order to focus stakeholder comments on the kinds of allocation decisions which will need to be made. This paper actually develops three distinct options to achieve AB 32 GHG emission reductions to serve as straw proposals for review and comment. Staff expects these options and others that will be designed by parties will be the subject of open discussion, modification or additions.

The Legislature listed several criteria that ARB must meet in implementing the State's GHG cap in Part 4 (Section 38562) and Part 5 (Section 38570) of AB 32. While these are important criteria for determining whether or not a cap-and-trade program should be implemented in California, for some of these requirements, we did not find that there was a different impact among the various allocation options examined in this paper. Many important policy criteria have limited impact on which allocation method to choose. The criteria used for evaluating options are based on the Interim Opinion's direction that allocation policy should ensure that GHG emissions reductions are accomplished effectively, at the lowest cost to consumers, and equitably. The four evaluation criteria that staff identified include: consumer cost, equity among customers of retail providers, simplicity, and accommodation of new resource entrants.

The paper analyzes three basic allocation options and variations on those options. For each option, staff discusses how a "pure" approach would work and then suggests a "preferred" modification to use if that overall approach is chosen. The paper will be partnered with modeling results presented by Energy and Environmental Economics (E3) to serve as a straw proposal for focusing parties on the choices which need to be made for recommendation to the ARB's 2008 Scoping Plan. Since staff did not have the completed modeling results in time for preparation of this paper and were not able to thoroughly compare the impact of the options on the California situation, the paper does not recommend an overall preferred approach. Stakeholder comments, workshops, and the material presented here will assist the joint Commissions in comparing alternative options and ultimately recommending a preferred approach.

The three allocation approaches examined are (1) administrative allocation to deliverers based on historical emissions, (2) output-based administrative allocation to deliverers (allowances granted based on electricity delivered), and (3) a large percent auction with distribution of auction revenue rights primarily back to retail providers on behalf of consumers. The three variations suggested by staff as the "preferred" methods are:

1. An initial administrative allocation of no more than 50% of allowances to deliverers on a historical emission basis. The remaining allowances could be distributed entirely by auction, or through a combination of auctioning and output-based allocation. The

share of allowances allocated on an emission basis would decline rapidly in subsequent years.

2. An initial allocation of 90% of allowances to deliverers on an output basis, with the remainder distributed by auction, transitioning to greater percentages of auctioning. Allowances would only be allocated to deliveries from GHG-emitting resources, and this would be done on a fuel-specific basis.

3. Initially auctioning 75% of allowances, with the remaining allowances allocated administratively. The majority of revenues would be recycled to retail providers on a historical emission basis for uses to implement the goals of AB 32, and the revenue allocation would transition slowly to be based on sales over time.

Table ES-1 summarizes how the allocation methods would perform compared to the evaluation criteria. For each basic method, both the pure and staff-preferred versions are shown. Checks indicate that the method would generally perform well according to that criterion, while an "X" indicates that it would perform relatively poorly.

Table ES-1. Summary of Evaluation Criteria Applied to the Allocation Methods

Allocation Method	Consumer Cost	Transfers among Retail Provider Customers	Admin Simplicity	New Entrants
Pure Emission-Based	✕/✓ [a]	✓	✓	✕
Preferred Emission-Based	✓	✓	✕	✓
Pure Output-Based	✓	✕	✓	✓
Preferred Output-Based	✓	✓	✕	✓
Pure Auction	✕	✕ [b]	✓	✓
Preferred Auction	✓	✓	✕	✓

[a] Emission-based allocation would not produce a transfer to producers for customers of fully-resourced vertically-integrated utilities.

[b] The degree of transfer among retail provider customers would depend on the distribution of the auction revenues.

The pure emission-based allocation of allowances to deliverers would perform well for two of the evaluation criteria. The primary drawback of a pure emission-based method is the risk of large additional profits to deliverers in competitive markets at the expense of most of the electricity customers in California served by investor-owned utilities and electric service providers. An additional concern is that new entrants in electricity markets would be disadvantaged compared to deliverers that had been granted a perpetual allocation of allowances. These two concerns are both addressed in the staff-preferred version in which only half of the allowances would be granted on a historical emission basis, at least 10 percent allocated by auction, and the rest distributed either on an output basis or by additional auctioning.

Both output-based methods would perform well in holding down consumer cost. Any output-based approach with frequent updating would also accommodate new entrants. The pure output-based approach differs significantly from the preferred approach with respect to transfers of funds among customers of retail providers. While the pure output-based approach would likely result in large transfers from customers of coal-dependent retail providers in the early years of the program, the preferred fuel-specific approach would produce virtually no transfers at the start of the program.

Evaluating the pure auction approach with regard to overall consumer cost and transfers among customers of different retail providers is difficult without specifying what happens to the money raised by the auction. Assuming that auction revenues in the pure auction approach are not used to mitigate consumer costs, auctioning would obviously have significant impacts on rates. Whether a large degree of transfer among customers of different retail providers would also occur depends on how auction revenues would be used. Presumably, under the pure approach, the auction revenues would be spent in ways that benefit all Californians equally. In the recommended auction approach, auction revenues would be distributed to retail providers on behalf of consumers – initially on a historical emissions basis and transitioning to a greater share allocated on a sales basis. This approach would reduce consumer costs and mitigate the concern of transfers among customers of different retail providers, but with some increased administrative complexity. The preferred auction option would also readily accommodate new entrants.

In addition to these staff recommendations outlined above, we have also attached to this paper two important papers on the subject of allowance allocation, which should aid parties' understanding of the allowance allocation issues we face in California.[1]

[1] Appendix A to this paper is a report by the National Commission on Energy Policy, while Appendix B attaches a paper by Resources for the Future developed for the Regional Greenhouse Gas Initiative in the Northeast U.S.

1. Introduction

1.1 Background

The Interim Opinion on Greenhouse Gas (GHG) Regulatory Strategies[2] jointly adopted by the California Energy Commission and the California Public Utilities Commission (Commissions) recommends that the Air Resources Board (ARB) adopt a multi-pronged strategy to reduce GHG emissions in the electricity sector. The approach relies primarily on energy efficiency and renewable energy mandates to meet AB 32 goals. In addition, the Commissions recommend a market-based mechanism to capture additional reductions, to contribute to the ambitious GHG emission reduction targets set forth in AB 32. For the market-based component, the Commissions recommend the establishment of a multi-sector cap-and-trade program, which includes the electricity sector, to deliver additional GHG reductions beyond mandatory measures at the lowest cost to Californians. The Commissions found that a cap-and-trade system "would achieve reductions in the least-cost manner by allowing for flexibility in achieving emissions targets through allowing obligated entities to rely on the least-cost abatement options throughout the economy."[3] Design of such a cap-and-trade program is the subject of further work in this proceeding (R.06-04-009).

Reviewers of this paper should note that the Commissions are undertaking a number of policy and programmatic efforts to address emissions reductions in the electricity and natural gas sectors. The joint Commission proceeding in which this paper is being released represents only one of several dozen venues in which issues related to AB 32 reductions are being addressed. For example, in separate venues, the Commissions are undertaking rulemakings on more aggressive building codes and appliance standards, big/bold energy efficiency programs for investor-owned utilities, statewide coordination of energy efficiency goals and strategic demand-side planning, renewable portfolio standard implementation, the California Solar Initiative, policies for combined heat and power facilities, and a host of other smaller programs and policies designed to produce GHG emission reductions in these sectors. While the bulk of the current proceeding is focused primarily on the best approach for implementing a market-based mechanism to provide additional GHG reductions beyond mandatory programmatic reductions, this proceeding should not be mistaken for the only, or even the main, initiative at the two Commissions related to AB 32 goals.

The two Commissions are working with ARB to ensure that all of the work associated with clean energy initiatives is reflected in the draft scoping plan produced by ARB. In this particular proceeding, the interim decision referenced above recommended both programmatic approaches and the development of a cap-and-trade program for the electricity sector. The remainder of this proceeding will develop recommendations necessary to implement a cap-and-trade system for electricity, should ARB decide that one is warranted. We recognize that in order to include a cap-and-trade system in its scoping plan, ARB is required by AB 32 to perform certain analyses. We do not further address those requirements

[2] Energy Commission Interim Decision CEC-100-2008-002-F (http://www.energy.ca.gov/2008publications/CEC-100-2008-002/CEC-100-2008-002-F.PDF) adopted March 12, 2008 and Public Utilities Commission Decision D.08-03-018 (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/80150.htm) adopted March 13, 2008.

[3] D.08-03-018, p. 5.

in this paper, but remain confident that ARB will fulfill those obligations. Instead, we focus our attention on developing further recommendations to deliver to ARB in the event that they determine that a cap-and-trade system should be designed that includes the electricity sector.

One of the main issues associated with cap-and-trade design is the manner in which responsibility is assigned to individual entities for participation in the program. These rights and responsibilities are called "allowances" and represent the right of a regulated entity to emit a certain quantity of pollution per allowance, usually one metric ton of CO_2 equivalent (CO_2e) for each allowance. At the conclusion of a compliance period, the regulated entities, which the Commissions have recommended be the deliverers of electricity to California's grid, must surrender the number of allowances that match the quantity of pollution emitted. Any shortfall would subject the regulated entity to fines and/or other enforcement actions. Because these allowances can be traded among regulated entities, these allowances have value – a value determined by the supply of allowances and the demand to emit GHGs.

A key aspect of designing cap-and-trade systems is determining a method for distributing GHG allowances. There are two main options for distribution of these allowances. The state may either allocate allowances administratively or it may choose to auction all or a portion of the allowances.

The Interim Opinion recommends to ARB that "some portion of the GHG emission allowances available to the electricity sector be auctioned."[4] This recommendation was predicated on the use of the majority of proceeds to benefit electricity consumers through investments in programs like energy efficiency and renewable energy or through direct customer bill relief.

In the Interim Opinion, the Commissions determined that the record was insufficient at the time to decide the appropriate percentage of allowances to auction, the manner in which to distribute auction proceeds, whether the share of allowances auctioned should change over time, and the method to be used for administratively allocating whatever allowances are not auctioned.[5] However, the Interim Opinion did provide some broad guidance about the direction of future recommendations on allocation.

> "In addressing allocation issues, we keep in mind that some deliverers of electricity to the California grid are also retail providers of electricity for consumers. We also recognize that allocation policy will have an impact on consumer costs. Our intent in developing additional allocation policy recommendations is to ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers. While we may wish to reward early actions to reduce GHG emissions in advance of 2012 when the AB 32 compliance period begins, it is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[6]

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4 D.08-03-018, p. 8.
5 D.08-08-018, p. 9 and p. 131.
6 D.08-08-018, p. 7.

Allocation is fundamentally a question of allocating the value that allowances represent. The State can conduct this allocation of allowance value either by administratively allocating the actual allowances themselves or by first auctioning allowances and then allocating the resulting revenues. Theoretically, any method of allocating actual allowances to various entities may be replicated by allocating auction revenues on an identical basis (CBO 2001).

For example, allowances could be allocated to GHG emitting facilities on a historical emissions basis, as is the case for approximately 97% of the SO_x allowances in the Acid Rain program. Similarly, allowances could be auctioned with the revenues returned to GHG emitting facilities in proportion to historical emissions resulting in the same distribution of allowance value (which is the case for the other 3% of SO_x allowances). The allowance value (i.e., the auction revenues) may be distributed according to defined auction revenue rights (ARRs).

A nearly infinite number of approaches to allowance allocation are possible. As many parties correctly noted earlier in this proceeding and as discussed in the Market Advisory Committee report, the question of the point of regulation in the electricity sector can be separated from the question of how allowances are granted and to whom. The Interim Opinion resolves the question of the point of regulation by determining that deliverers of electricity to the California grid should have responsibility for the emissions associated with that delivered power. Deliverers are the entities who will ultimately be required to surrender allowances at the end of a compliance period in the cap-and-trade system to show that they have covered their emissions with sufficient allowances. If they do not do so, they could be subjected to penalties and/or fines.

Therefore, we assume that the deliverers are the entities who will ultimately require access to allowances. However, it does not necessarily follow that allowances must be granted to the deliverers if they are administratively allocated. It is possible that allowances (or their value) could be granted to regulated or publicly-owned retail providers of electricity on behalf of their consumers. Throughout this paper, we bear in mind that ultimately consumers will be paying the cost of these allowances that will eventually become embedded in their cost of electricity. The manner in which allowances are allocated can have profound effects on the prices consumers will ultimately pay for their electricity. Thus, our ultimate goal is to design allowance allocation policy to ensure that the GHG reductions in the electricity sector are delivered at the lowest possible cost to consumers under this structure.

1.2 Scope of the Staff Paper

For purposes of this paper, we assume that the electricity sector participation in a cap-and-trade system will occur in the context of a multi-sector program statewide in California. It is possible that in that context, ARB could decide to hold a multi-sector auction in which all participating sectors must purchase their allowances. In that situation, there would not be a need for as detailed a recommendation as we contemplate here, though the state would still need to determine how revenues from the auction would be allocated to certain sectors or GHG-reducing activities within the state.

However, if some administrative allocation to sectors is contemplated, which we assume here, allocation of allowances (or allowance value) in a multi-sector program will likely occur in two stages. First, the State will need to determine the number of allowances to allocate to each sector. Then a method will need to be selected for allocating among affected entities within each sector. This staff proposal focuses exclusively on the question of how to allocate a given amount of allowances to entities within the electric sector. It does not make a recommendation on the issue of how many allowances should be allocated to the electric sector, assuming that ARB does implement a multi-sector cap-and-trade system. However, some values for allocation to the electric sector are used for illustrative purposes at various points in this paper. In addition, the Commissions expect to provide guidance to ARB on the question of electric sector responsibility for reductions separately from the allocation issues, informed by modeling work being conducted by Energy and Environmental Economics (E3). Parties will have an opportunity to comment on this information and analysis separately.

This paper is part of a suite of program design issues to be addressed in this part of the proceeding. Modeling by E3 will also analyze revenue requirements of the seven retail provider groupings in their model that may result from various scenarios of allowance prices, allowance allocation, and flexible compliance mechanisms. The record will also be developed separately for flexible compliance mechanisms (such as offsets, banking and borrowing, and other price stabilization measures) and other design and implementation questions.

Since the aim of this paper is focused on the basis for allocating allowance value among electricity sector entities, staff has not delved into the finer points of auction design. While it is critically important to design auctions in a way to prevent collusion and abuse of market power, we expect that auction design will be undertaken later under ARB guidance, if ARB decides to explore auctions as an allocation mechanism in its scoping plan. We also refer parties who are interested in this topic to an auction design report that was commissioned for the Regional Greenhouse Gas Initiative (Holt et al. 2007).

Given the complexity of this topic and the ramifications to retail providers and their customers of distributing potentially billions of dollars of allowance value each year, staff analysis in this paper only provides options to the Commissions at an intermediate level of detail. Recommendations in this staff paper are provided in suggested ranges of percentages to auction or freely allocate rather than firm commitments to specific percentages or timetables. Staff expects that additional refinement of the recommended allocation methods will occur between the decision the Commissions will issue later this year and the release of ARB's implementation plan, which must be completed by January 1, 2011.

1.3 Structure of California's Electricity Sector

Evaluating the implications of various allocation methods is complicated by the mixed market structure that exists in California. Most customers in California are served by retail providers that largely rely on independent power producers and marketers in competitive wholesale markets, while others are served by fully-resourced, vertically-integrated utilities. Customers that depend on wholesale markets consist mostly of those served by investor-owned utilities (IOUs) but also include customers of electric service providers (ESPs) and many of the publicly-owned utilities (POUs). Some allocation methods are likely to have different impacts on the customers of fully-resourced utilities compared to customers that are market dependent. In particular, some allocation methods may create the potential for substantial windfall profits for independent generators and/or deliverers, an outcome that customers of fully-resourced utilities may be shielded from by rate regulation and/or their public ownership structures.

Currently, some retail providers have a high carbon-emitting resource base, while others are relatively low-carbon. Some areas of the state are growing quickly, while others are growing slowly or not at all. These differences mean that retail service providers who choose to reduce their carbon footprint will have different trajectories for doing so and will have more or fewer requirements to change over their infrastructure by 2020 and beyond. By choosing deliverers of electricity as the point of regulation for the electricity sector, we have made the stake of retail providers overall in California more indirect than would have been the case under a load-based system. Deliverers (representing electricity supply, not demand) will be the entities responsible for covering their emissions, though of course a number of deliverers (particularly publicly-owned utilities) are also retail providers.

In addition, there is wide diversity in the types of resources upon which retail providers in California rely for delivering power to consumers. The range of renewable resources in the portfolios of various retail providers can range between close to zero and 60%, depending on the utility.

In assessing the different approaches of allocating allowances in the electricity sector, we have attempted to take these different market structures and resource portfolios into account to devise approaches that minimize redistributive outcomes while treating deliverers consistently.

1.4 Structure of this Paper

The criteria used to evaluate among allocation methods are explained in Section 2. A brief overview of the three main methods of allocating environmental allowances is given in Section 3, followed by a discussion in Section 4 of combined heat and power (CHP) and compensation for early voluntary action, two topics related to allowance allocation that are not analyzed in depth in this paper. Sections 5, 6, and 7 delve into more detailed analysis of each of the three main allocation methods. Each of these sections explains the "mechanics" of how a particular method would be implemented, provides an assessment of the likely outcome of implementing a "pure" version of that approach, and presents the staff recommendation for a potential program design using that approach. Section 8 summarizes the staff recommendations.

2. Evaluation Criteria for Allocation Options

Staff developed evaluation criteria to help guide the analysis of the allocation options. We have limited the set of criteria to those that are most germane to allocation and excluded criteria for which all options are likely to perform equally. Other criteria have been included in the Market Advisory Committee (MAC) report and the Commissions' previous decisions and rulings in this proceeding. Some of these criteria pertain to other elements of system design or the interaction between a GHG cap-and-trade program and regulation of local air pollutants.

The legislature listed several criteria that ARB must meet in implementing the State's GHG cap in Part 4 (Section 38562) and Part 5 (Section 38570) of AB 32. For some of the requirements, we did not find that there would be a different impact among the various allocation options examined. For example, compliance with the requirement that future regulations (Section 38562(b)(4) and Section 38570(b)(2)) must prevent any increase in the emissions of toxic air contaminants or criteria air pollutants does not depend on the allocation approach. That is a function of the total number of allowances issued and the continued enforcement of other federal, State, and local air pollution regulations. Additionally, Section 38570(b)(1) requires ARB to consider "localized emission impacts in communities already adversely impacted by air pollution." This requirement also does not help to differentiate one allocation method from another because, once issued, an allowance may be used by any regulated electricity deliverer or other source in any location. As stated in the Interim Decision, the Commissions expect that any program to regulate GHGs must also be consistent with other federal, State, and local environmental regulations.

Similarly, the requirement that the design achieves the maximum feasible, cost-effective reductions at lowest cost to California is one reason for recommending a market-based mechanism, but allocation is primarily an issue of distribution of the resulting costs and benefits among different sectors of society, not the total cost to society. We recognize that AB 32 requires achieving real GHG reductions, which is the focus of all of our efforts. However, that requirement does not help us distinguish among allocation options; it is chiefly a function of how the declining cap is set for the cap-and-trade system as a whole.

For other AB 32 criteria, we did find that the allocation methods may have different impacts. Those criteria are incorporated into the list below that staff determined best differentiate the allocation options.

2.1 Consumer Cost: Impacts to Retail Electricity Customers

Consumer costs refer to the expenditures that end users of electricity will incur as a result of the cap-and-trade program. As noted above, the Commissions have determined that deliverers of electricity should face the compliance obligation. However, the cost of that compliance will ultimately be passed on to consumers on their electricity bills. Consumer cost consists of two elements: the true social cost of mitigation (reductions in GHG emissions) that is borne by consumers and transfers of wealth from consumers to producers (or deliverers). Some methods of allowance allocation are likely to yield large transfers of wealth from consumers of electricity to producers or deliverers. This occurs when producers are largely compensated for GHG costs through increased prices while also receiving allowances freely (CBO 2001; Burtraw and Palmer 2007; NCEP 2007; MAC 2007). This criterion is related to Section 38652(b)(1) and Section 38652(b)(2) of AB 32.

Note that a trade-off exists between the total social cost of reducing GHGs and reducing consumer cost in ways that blunt the price signal. Allowance value can be distributed in various ways, some that reduce the economic burden on consumers by directly mitigating the price impact and others that provide additional income to consumers without affecting prices. A price-mitigating approach entails using allowances to encourage output (described in more detail in Section 6) or to lower retail electricity rates. Examples of income-enhancing approaches are the use of auction revenues to reduce personal income tax rates or to provide lump-sum payments to households. Price-mitigating approaches induce greater consumption than income enhancing refunds that leave consumers exposed to the full embedded GHG cost of the energy they consume (Burtraw and Palmer 2007). To the extent that consumers are shielded from the costs, GHG targets must be reached either by achieving greater reductions in other sectors or by reducing the GHG intensity of electricity to a greater degree than would otherwise be necessary.

2.2 Equity Among Customers of Retail Providers

As the Commissions state in the Interim Opinion, "[I]t is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[7] Thus, under this criterion, any recommended allocation method should not result in large redistributions of funds from one set of retail provider consumers to another as a result of actions taken prior to AB 32. While retail providers who are also deliverers should be encouraged to achieve positive environmental performance, the allocation method should not result in redistribution of wealth among the customers of retail providers for reasons unrelated to mitigating climate change, such as access to or dependence on resources determined largely by geographic or historical circumstances. This criterion is consistent with Section 38562(b)(1).

Again, we emphasize that the compliance burden will be on deliverers of electricity. In some cases, deliverers are also retail providers, to varying degrees. To determine the impacts of various allocation options on consumers of retail providers requires a complex analysis of differing circumstances related to the supply of electricity.

It is also important to point out the difference between allocation methods that redistribute wealth due to retail providers' differential starting points and the flows of allowance value that occur as a benefit of trade. Under any allocation option, some sets of consumers of some retail providers will face higher costs than others purely because their costs to reduce greenhouse gas emissions will be higher. Much of the value of a cap-and-trade system can be found in equalizing those costs of reductions across the entire sector by allowing trading to occur. If the cost of reductions is less onerous in a particular geographic area, deliverers with more expensive costs of mitigation should instead be willing to buy allowances from those who have lower costs of compliance.

[7] D.08-03-018, p. 8.

2.3 Administrative Simplicity

Staff recommends that policymakers choose an allocation method that is easy to understand and administer. This is desirable because stakeholders need to be able to reasonably predict the consequences of the program. This criterion is drawn from Section 38562(b)(7).

2.4 Accommodation of New Resource Entrants

Under this criterion, allocation methods should not inhibit new deliverers of electricity from entering the market. New market entrants may be able to provide cost-effective emission reductions by bringing new, low-GHG power online. This is consistent with Section 38562(b)(1), Section 38562(b)(5), and Section 38562(b)(6).

3. Overview of Allocation Methods

Allowances may be allocated using any number of methods. The two basic options for allocating allowances to regulated entities are administrative distribution and auction. Administrative distribution usually entails the free allocation of allowances to regulated sources, although the allowances could also be made available at a fixed price rather than distributed for free. Two methods of administrative allocation, emission-based and output-based, are commonly described in the cap-and-trade literature, but many other variations are possible.

Previously in this proceeding, the Commissions received comments from parties that proposed certain allocation methods that have not been employed to our knowledge and that have been subjected to much less analysis in the economic literature. These proposals are not discussed in this paper. They may have merit, but we have fewer tools and historical examples to assess them. The proposals include the "economic harm" method suggested by Southern California Edison,[8] an allocation of rights to purchase allowances at a fixed price suggested by the Green Power Institute, and an allocation of allowances to all Californians on an equal per capita basis submitted by the Climate Protection Campaign.[9] While parties to this proceeding are free to provide more information and analysis of these options, we do not pursue them further in this paper.

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[8] Staff is aware of only one study that has modeled this method of allocation. Burtraw and Palmer (2007) modeled the effect of auctioning and emission-based allocation on the market value of U.S. electricity generators at the facility, firm, and industry level. The findings indicate that at the low allowance prices modeled, full auctioning would cause a loss in market value of $50 billion for certain generation facilities; however, another group of facilities would gain $41 billion of market value. At the generation firm level, losing firms suffer a loss of market value of $14 billion, but other firms gain market value of $5 billion. At the industry level, the total loss is $9 billion, or roughly 6% of the $141 billion total net present value of the allowances issued. Compensation at the facility level would, in this example, overcompensate the industry by $41 billion, while compensation at the firm level would overcompensate the industry by $5 billion. This report demonstrates the complexity of determining what might constitute "economic harm." Implementing this method in practice would seem to require that loss in market value be accurately predicted at the firm level if allowances were to be allocated according to a pre-determined formula or schedule.

[9] These comments were submitted in response to the ALJ Ruling of October 15, 2007.

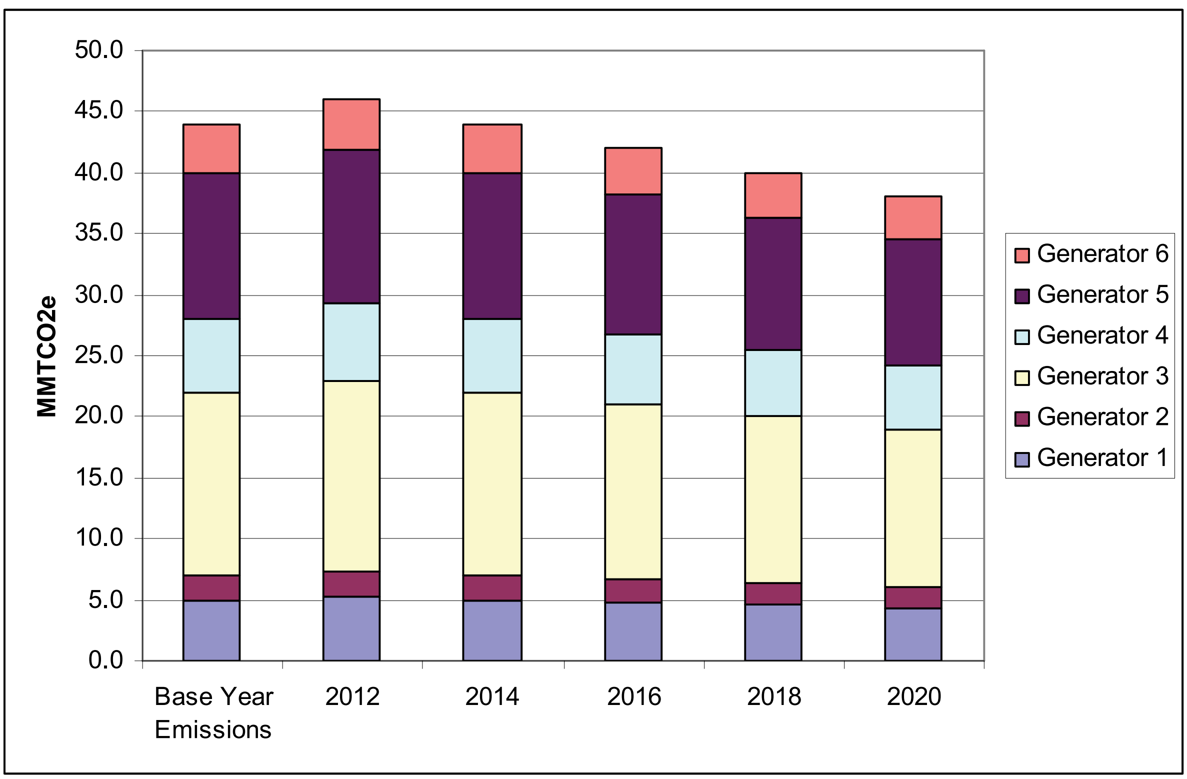
Three basic allocation method options will be covered in this paper: emission-based allocation, output-based allocation, and auction.

3.1 Emission-Based Allocation

Under some existing cap-and-trade programs for air pollutants, allowances have been allocated to sources on an emission basis, generally in proportion to the emissions produced during a baseline period.[10] For example, a facility that emitted 5% of the emissions during the baseline period would receive 5% of the allowances distributed during a given compliance period. Usually, the baseline period is static. In other words, once the baseline period proportions have been established, they are never updated. This is typically to avoid any potential incentives for sources to increase their emissions in order to receive a higher allocation in an updated period.

The EPA's Acid Rain program and Phase I of the European Union Emission Trading Scheme (EU ETS) both allocated most allowances to sources on the basis of a historical baseline period. As the total number of allowances declines over time, each entity receives fewer allowances, in proportion to the overall decline in the cap. In the Acid Rain program, this is done in equal proportion across all facilities, as shown in Figure 1. Other methods are possible, such as steeper rates of decline for higher-emitting facilities.

Figure 1. Emission-Based Allocation of Allowances with Equal Rate of Decline



[10] This method is often referred to as "grandfathering."

In the Acid Rain program, the allowances are allocated according to baseline period emissions in perpetuity, even if a facility shuts down. However, some EU ETS member countries have different rules that require the allowances issued to a closed facility either to be transferred to a new facility owned by the same firm or be surrendered back to the government.

3.2 Output-Based Allocation

Output-based allocation methods give allowances to regulated entities according to their output. In the electricity sector, this would entail giving allowances to deliverers for every megawatt-hour (MWh) delivered to the California grid. Several variations of an output-based approach are possible. The eligible pool of delivered electricity can be restricted by fuel or technology types, which increases the rate at which the remaining deliverers receive allowances. Such a method tends to incentivize those entities that produce their outputs at lower emission rates and disincentivize those whose production is more emission intensive. This is because although allowances would be granted based on MWh delivered, deliverers would still need to surrender enough allowances for compliance purposes to cover all of the emissions associated with their electricity deliveries. Thus, deliverers with cleaner than average portfolios will have excess allowances, while those with more carbon-intensive portfolios will need to buy allowances to cover their emissions.

Output-based approaches are usually discussed in combination with updating, but they could be used without updating. "Updating" refers to a variation on administrative allocation methods in which changes in regulated entities' production or emissions have some impact on their future allocations. In other words, the baseline upon which the allocations are based will be updated periodically to reflect changing circumstances. Updating is generally considered with output-based allocation methods because it does not create a disincentive for emissions reductions the way it would if updating were used with an emission-based method. In this staff paper, we assume that output-based allocations would also be regularly updated.

3.3 Auction

Under this method, some quantity of allowances is auctioned by the State on a periodic basis. A wide variety of auction designs are possible, with different options for the frequency of the auctions, limitations on participation in the auction, and the manner in which bids are made and prices set in the auction. For example, auctions could occur on an annual, quarterly, or monthly basis. Auction participation could be completely open, limited exclusively to the entities regulated under the cap-and-trade program, or regulated entities could have the option to bid on an initial block of allowances with the remaining portion auctioned in open rounds.

A crucial distinction between auctioning and administrative allocation of allowances is that while auctioning is a method of distributing allowances, it is not a method of distributing allowance value. Because auctioning generates revenue, further decisions must be made about the disposition of the funds raised through the auction. One option for distribution of these funds, as discussed in this paper, is the allocation of auction revenue rights (ARRs). These can be assigned on the same bases possible for allocation of allowances themselves (i.e., historical emissions, output basis, sales basis, etc.). The ARRs can also be assigned to entities other than those with the compliance obligation. For example, in this paper we consider the distribution of ARRs to retail providers on behalf of their consumers. We also discuss the option for allocating allowances directly to retail providers, but requiring that they sell those allowances at auction to generate revenues for consumer purposes.

In all discussion of auctioning in this paper, we assume that the auction itself, if one comes to pass, would be conducted by ARB and/or its agent.

3.4 Combining Different Methods

These three methods may be used in various combinations by setting aside one portion of the pool of allowances to be allocated by one method with the remaining portion allocated using a different method. For example, 50% of the allowances could be allocated on an emission basis and 50% allocated on an output basis.

If a combination of methods is used, the shares of the allowance pool allocated according to each method can change over time. For example, equity considerations might argue against an emission-based allocation in perpetuity. Facilities that have shut down no longer have any need for allowances, and it is difficult to justify a permanent source of income to the shareholders of companies that operated these facilities during the baseline period.

4. Other Issues Related to Allocation

4.1 Allocation and Early Voluntary Reductions

This staff paper does not address the question of early voluntary reductions per se. ARB is continuing to develop guidelines for recognizing early reductions, and subsequent workshops or rulings in this proceeding may seek input from parties on this topic. However, it is worth noting that two of the allocation methods described above indirectly reward early reductions – auctioning, by reducing the number of allowances that must be purchased, and output-based, by reducing emissions relative to the benchmark rate (MAC 2007, p. 61). While emission-based methods may not compensate entities that undertook GHG-reducing actions prior to the time period used to establish the baseline, they reward GHG-reducing actions performed after the baseline period but prior to the compliance period. If an emission-based allocation method is pursued, it may necessitate greater attention to the development of measures that directly reward early action.

4.2 Allocation to Combined Heat and Power Facilities

In the Interim Opinion, the Commissions state,

> "[W]e plan to consider further the treatment of combined heat and power (CHP) facilities under this policy framework. We want to avoid unintended negative consequences for CHP, which may be a valuable source of additional GHG emissions reductions in California. Therefore, we intend to consider further the treatment of emissions from CHP facilities in the next portion of this proceeding…"[11]

[11] D.08-03-018, p. 10

This paper does not address the issue of how best to incorporate CHP facilities into a multi-sector cap-and-trade program. A forthcoming staff paper will consider CHP issues in more depth. That staff paper will take into account the three different staff recommended allocation methods proposed in this paper. Since it is primarily the allocation of allowance value that may inadvertently harm CHP facilities in a cap-and-trade system relative to other producers and consumers of electricity, we provide a few key thoughts on the interaction between CHP and allocation methods.

Regardless of the sectoral classification of CHP recommended in a cap-and-trade program design, allowances should be allocated in a manner that avoids inadvertently deterring either the continued operation of or new investment in CHP solely because of the allocation method chosen. Our concern here is to design an allocation method that avoids inadvertently discouraging CHP. In this paper, we take no position now on whether CHP systems should be deliberately incentivized by the allocation method or in any other manner.

Depending on the method of allocation, the cost impact of the cap-and-trade system can be cushioned at either the production or consumption side of an electricity transaction. Since sites with CHP facilities are both producers and consumers of electricity, staff recommends that the allocation option chosen should maintain a level playing field for both activities.[12] To do this, all generation by CHP facilities, whether used on-site or delivered to the grid, should at a minimum receive allowances in a manner consistent with the rules applied to electricity that is delivered to the grid by other deliverers. Additionally, any funds made available for rate relief for electricity consumed from the grid should be available at the same rate for on-site consumption from CHP facilities. Differential treatment of either consumption or production could have the effect of discouraging (or incentivizing) CHP. Recommendations regarding an overall approach to treatment of CHP under an electricity sector cap-and-trade system will be explored in further depth later in this proceeding.

5. Emission-Based Allocation to Deliverers

5.1 Mechanics

An emission-based allocation distributes emission allowances freely to deliverers or other emitting entities in proportion to the emissions produced during a baseline period. The EU ETS, the Regional Clean Air Incentives Market (RECLAIM) program in Southern California and the EPA's Acid Rain program all allocate most allowances based on historical emissions. In RECLAIM, regulators issued allowances to emitting entities in proportion to their highest annual emissions level between 1989 and 1991, less reductions from regulatory requirements established after 1992. In the EU, each Member State received its own emission allocation based on emission levels from 1998 through 2002. In the EPA's Acid Rain program, emissions were set based on an estimated emissions rate multiplied by average fuel consumption between 1985 and 1987. Regulators sought a baseline year that was not impacted by abnormal production conditions. In each of these systems, allocations are proportionally reduced at pre-determined intervals as the emissions cap decreases.

[12] We do not address allocation for useful thermal output in this paper.

We do not have adequate information to make a specific recommendation in this paper regarding the appropriate baseline period if emission-based allocations are employed in the electricity sector. Since the electricity sector is subject to large swings in emission levels due to hydro generation and weather variability, staff recommends that the baseline period should, to the extent possible, be based on one or more years marked by average levels of hydro generation and average cooling degree-days.[13] Establishing an averaged multi-year baseline may help accomplish this goal, as well as reducing the impact of annual variations in deliveries from individual deliverers.

One challenge to distributing allowances using historical emission-based allocation involves distributing emission allowances to deliverers of unspecified power. After establishing a baseline period, the State would need to determine the emissions associated with unspecified power in order to allocate the appropriate allowances to the responsible deliverers.

5.2 Analysis of a Pure Emission-Based Approach

A pure emission-based approach would consist of identifying the deliverers of electricity to the California grid during the baseline period and determining the emissions associated with those deliveries. All of the allowances for each vintage would be allocated to the entities identified as delivering electricity during the baseline period in proportion to their emissions during the baseline period. The allocations would decline at the same rate for each identified deliverer and would continue in perpetuity.

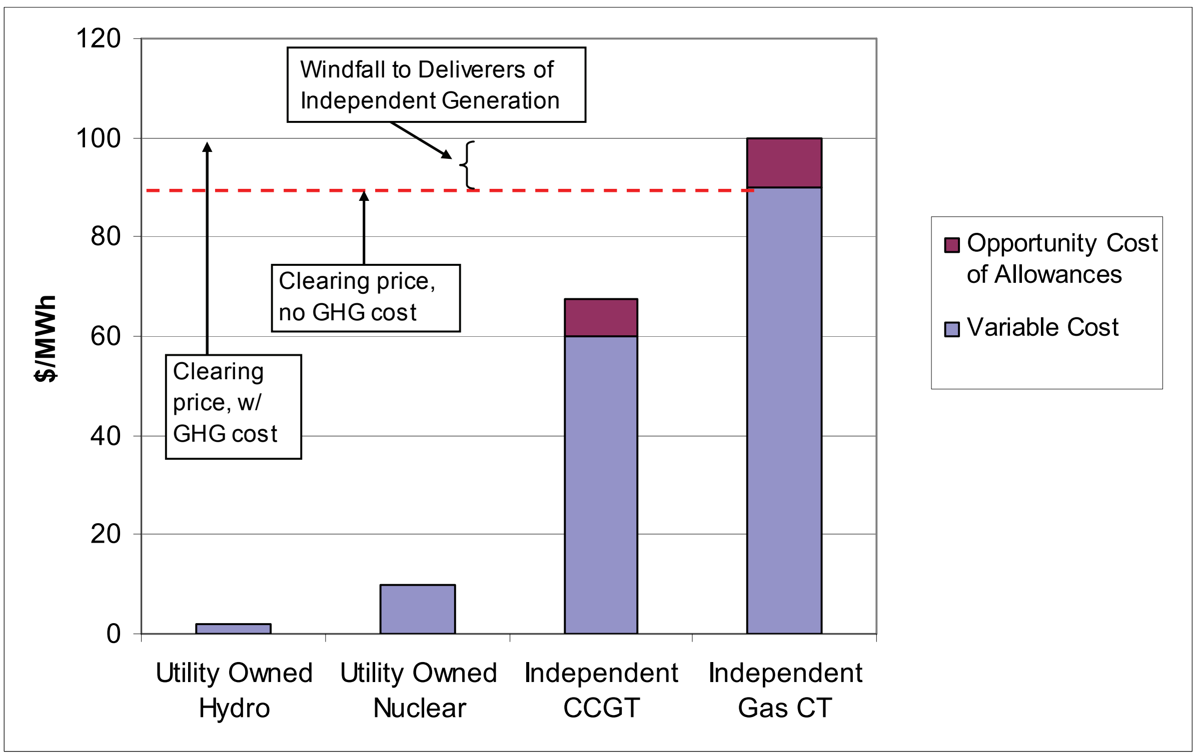
The primary concern about implementing this approach is the likely impact it would have on consumer costs. Regardless of the allocation procedure used, allowances have monetary value. This value is determined by supply and demand. By restricting carbon emissions, a GHG cap-and-trade program would create demand for allowances, since deliverers would no longer be able to emit GHGs without cost. Economic analysis of emission-based allocation predicts that the value of allowances will be factored into electricity costs despite the allowances being allocated freely (Burtraw et al 2001, NCEP 2007, Cramton and Kerr 2002).

To understand why the allowance value would be included in electricity prices, imagine a deliverer with a power plant that emits 0.5 metric ton CO_2e for every MWh generated and allowances are trading at \$40. In this case, each MWh has an allowance opportunity cost of \$20. Assume the deliverer bids into the spot market at its marginal cost of \$70 per MWh without including the value, or opportunity cost, of the allowance. In this example, assume that the market clears at \$80 per MWh. The deliverer makes \$10 per MWh by delivering power into this market. However, if the deliverer had not run its power plant, it would have been able to sell its allowances at the rate of \$20 per MWh. By not factoring the opportunity cost into its bid, the deliverer would be worse off by \$10 for every MWh it delivers than it would have been had it not run its power plant at all. In order to be indifferent between delivering power into the market or not, the deliverer would need to increase its bids to \$90 per MWh.

[13] The baseline period should not include future years closer to the start of the cap because that would create a perverse incentive to emit more GHGs during the baseline years.

Deliverers serving market-dependent retail providers are very likely to pass through most of the opportunity cost of allowances in their bid prices, which in turn would be reflected eventually on consumer bills. This phenomenon would not be as likely to affect fully-resourced retail providers (those owning sufficient generation to meet their own loads), assuming that they would be restricted by their governing boards or regulators from passing on the opportunity cost of the allowances to their customers (Burtraw and Palmer 2007). Figure 2 depicts how the opportunity cost of allowances would result in substantial additional profits for deliverers of independent generation.[14] The additional profits would not accrue for utility-owned generation if the bodies that oversee those regulated or publicly-owned deliverers do not allow the opportunity cost of freely allocated allowances to be passed through to customers.[15]

Figure 2. Illustration of Potential for Windfall Profits that Accrue to Deliverers of Independent Generation



In order to roughly estimate the annual potential for windfall profits, staff examined the 2005 California Climate Action Registry Power/Utility Protocol reports for the four largest market-

[14] Additional profits earned by a firm or industry that are unrelated to additional work or output are generally referred to as "windfall" profits in economics.
[15] This would not apply to surplus generation belonging to one utility that is bidding into a competitive market to serve other loads.

dependent retail providers in California.[16] (CCAR 2008) These reports provide the total quantity of wholesale power purchased from independent generators, other utilities, and marketers, in most cases disaggregated by resource type. Table 1 shows the result of this analysis. The four retail providers listed purchased over 112 million MWhs of electricity in 2005. For this calculation, it is assumed that the marginal source of power is usually a deliverer providing power from a gas-fired generator. At an assumed allowance price of $20 per metric ton, the opportunity cost of a gas-fired generator with an emission rate of 0.4 metric ton per MWh is $8 for each MWh generated.[17] If the opportunity cost were fully passed through, independent deliverers would stand to benefit from nearly $900 million a year in windfall profits.

Table 1. Potential Losses to Customers of Four California Retail Providers due to Windfall Profits, $20 per Metric Ton Allowance Price

Retail Provider	Million MWh Purchased in 2005	Potential Windfall Profit Paid to Deliverers, Million $ [a]
Pacific Gas and Electric	47.3	$378
Sacramento MUD	8.0	$64
San Diego Gas & Electric	12.9	$103
Southern California Edison	44.0	$352
Total	112.2	$897

[a] Assumes wholesale price set by marginal generator with emission rate of 0.4 metric tons per MWh.

For several reasons, the estimated values shown in Table 1 may err significantly in either direction. This analysis may overstate the windfall potential in the early years of a cap-and-trade program because many deliverers would be constrained by the prices specified in long-term contracts. As those contracts expire, the deliverers would be able to renegotiate and take advantage of the higher price of the marginal generators. The windfall potential could eventually be much higher than the estimates shown if allowance prices increase much above $20 per ton. This analysis also did not take into account the customers of ESPs and other market-dependent POUs. This table is intended as illustrative only to indicate the potential order of magnitude of this issue under an emission-based allocation.

Many countries in the EU have competitive wholesale markets, similar to the markets that provide power for the majority of California's load. Analysis of the experience in the EU ETS Phase I has shown that opportunity costs were in fact reflected in electricity prices even though more than 95% of the allowances were allocated freely on a historical emissions basis. In Germany and the Netherlands, which both have competitive wholesale electricity markets, pass-through of the value of freely allocated allowances was found to range from 60% to nearly 100% (Sijm, Neuhoff and Chen 2006). In the UK, the MAC report states that generators in the electric sector benefited from £500 million in windfall profits in the first

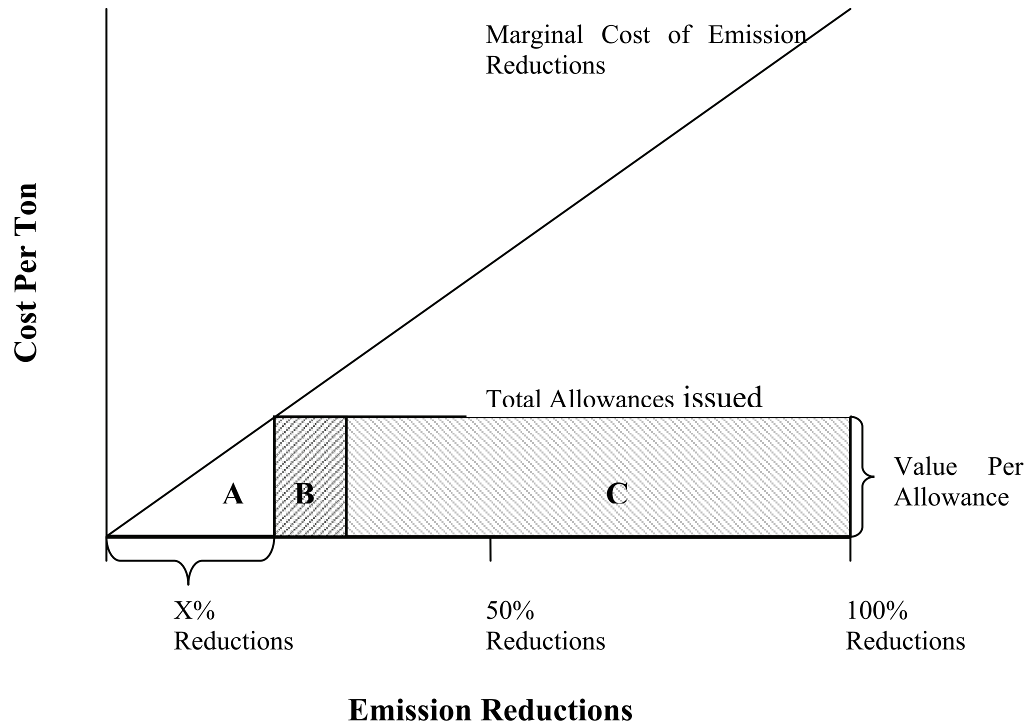
[16] Los Angeles Department of Water and Power is not shown since it is fully resourced and wholesale purchases are only a small percentage of its total generation.
[17] It does not matter if some of the generation comes from zero-emitting resources that have no compliance obligation; deliverers of power from those resources still benefit from the increase in the selling price of the marginal generators as consumers will pay the market clearing price.

year alone (MAC 2007, p. 56). A report produced for the UK government estimated that annual windfall profits in the electric generation sector would exceed £800 million annually (IPA Consulting, 2005). Point Carbon (2008) estimates that emission-based allocations to electric generators in the UK will yield £6-15 billion in profit increases resulting from the pass-through of carbon allowance value during Phase II (2008-2012) of the EU ETS.

The State may determine that some compensation to existing entities is appropriate to compensate them for the cost of compliance-related expenditures and to avoid negative impacts to entities for investment decisions made prior to GHG regulation. However, as both the theoretical literature and recent experience with the EU ETS demonstrate, emission-based allocation can result in regulated entities receiving allowance value far in excess of the cost of regulation (Sijm, Neuhoff, and Chen 2006; NCEP 2007; Cramton and Kerr 2002; Bovenberg et al., 2003; Burtraw and Palmer 2007; Burtraw, Palmer, and Kahn 2005).

A free allocation would likely result in large profit increases for deliverers who are not also retail providers. Figure 3 helps demonstrate this point, showing the costs of mitigation and value of allowances under an emission based allocation method. The upward sloping line represents the marginal cost of reducing emissions. It assumes that early reductions can be made at minimal cost and that the cost of emission reductions increases linearly with each additional unit of emission reduction. This example assumes that the State is requiring industry-wide reduction of emissions by X percent. The total cost of reaching X percent of emission reductions is equal to the area of the triangle A.

Figure 3. Illustration of Relationship between Allowance Value and Cost of Compliance



Under an emission based allocation, firms would receive allowances equal to the level of emissions they are allowed to emit. The value of these allowances will be equal to the marginal cost of the last unit of emission reduction. Shown graphically in Figure 3, the total value of these allowances would be equal to the area of the shaded rectangles B and C. As the graph shows, the value of the allocated allowances far exceeds the total cost of emission reductions, represented by triangle A. During the early years of the cap, when reduction requirements are low, the cost of emission reductions are small relative to the value of the allowances issued.

Compensating the entire industry for the cost of carbon emission regulation can be accomplished by freely allocating a fraction of the total available allowances. Rectangle B in Figure 3 represents an area equal to triangle A, the cost of compliance. By freely allocating allowances equal to rectangle B, the State can compensate the industry for their cost of complying with carbon emission regulations.

Staff notes that in light of the EU's experience with windfall profits, EU leaders are considering methods of transitioning the electric sector away from the current emission-based system used under the EU ETS. The European Commission is evaluating the use of full auctioning in Phase III, particularly in the electric sector because it is not subject to international competition (European Commission 2008, pp.7-8). [18] The Environmental Audit Committee of the UK House of Commons urges the UK Government to press for full auctioning of allowances in the future and that in particular the electric sector should be subject to 100% auctioning in Phase III (UK House of Commons EAC 2007, p.53).

When allowances were distributed for SO_x emissions under the Acid Rain program, circumstances differed markedly from the current electricity market structure in California. Allowances in the Acid Rain program were allocated to regulated electric utilities. As these utilities were subject to rate regulation, they were not able to capture the value of allowances in the form of higher consumer prices. As a result, the price effects of SO_x allowance pass-through were limited under the Acid Rain program (Cramton and Kerr, 2002).

Staff has identified several key impacts that would result under a pure emission-based allocation. Below is a summary of our analysis of a pure emission-based approach using the four evaluation criteria:

- The degree to which opportunity costs are passed on to customers is related to the portion of power that their retail providers purchase from the market and the change in the wholesale power price. To mitigate price increases the governing boards (or other regulators) of fully-resourced, vertically-integrated utilities are unlikely to allow pass-through of the value of allowances, while independent deliverers will pass opportunity costs through to retail providers who purchase power in wholesale markets. The market-dependent retail providers (IOUs, ESPs, and some POUs) will have to recover these higher costs by raising retail rates. The pass-through cost of carbon allowances can result in a large transfer of wealth from customers to deliverers of independent generation.

- Emission-based allocation would not result in large transfers among customers of retail providers.

- With regards to administrative simplicity, emission-based allocation is likely to be more complex to administer than an auction system. These challenges are related to determining a baseline period and estimating the emission levels associated with the generation of each deliverer.

- Under a historical emission-based allocation, new entrants face a competitive disadvantage. New entities participating in the market would need to purchase allowances, while their existing competitors would receive them for free. Allowances can be set aside for new entrants, but this increases the administrative complexity of the program. If not designed carefully, providing free allowances to GHG-emitting deliverers could encourage development of fossil-fuel generation, causing firms to invest in emitting resources over non-emitting resources that might otherwise be more attractive investments without the free allocation (Ahman, Neuhoff and Chen, 2006).

[18] Where energy-intensive sectors face competition from uncapped jurisdictions, if the allowances needed for that sector were only available by purchase at auction, that cost might induce leakage, thereby undermining the objectives of the cap-and-trade program. Administrative allocations to these sectors can mitigate this problem.

5.3 Preferred Emission-Based Approach

A pure emission-based allocation would almost certainly result in considerable windfall profits for independent (non-utility) deliverers in competitive wholesale markets. Because of this inherent trait of emission-based allocation, staff suggests that if an emission-based method is adopted, it only be used in combination with other approaches, in order to minimize the impact on consumers' costs. If the State decides to adopt an emission-based allocation, staff recommends that the system begin with a mix of emission-based allocation and auctioning or output-based allocation. Staff recommends that the system transition to either full auctioning or a mix of auctioning and output-based allocation over time.

Researchers have attempted to determine the share of allowances needed to compensate entities for the costs they face under a GHG cap-and-trade system. Harrison et al. (2007) surveyed studies and models that explored the compensation requirement to offset the costs for entities in the electric sector. Of the 11 studies sampled, they found that compensation for the electricity sector required between 5-50% of allowances. The wide range of results can be attributed to different data sets, compliance regions, allowance price assumptions and other variables. These studies generally considered the overall sector-wide compensation required. Only one of these studies considered lifetime compensation requirements, while the rest focused on compensation required over a limited program duration. Actual compensation at the firm level would likely vary considerably even if sector-wide compensation was accommodated by an allocation system (Harrison et al., 2007; Burtraw and Palmer 2007). According to the National Commission on Energy Policy report, freely allocating 50% of allowances based on historical emissions – with the remaining allowances auctioned – would be necessary to fully compensate entities in all sectors of an economy-wide system, though they do not consider the specific compensation required for the electricity sector (NCEP, 2007). Stavins (2007) also finds that 50% free emission-based allowances, coupled with a declining allocation over 25 years, approximately compensates entities of all sectors in an economy-wide system.

Staff recommends that, if adopted, an emission-based allocation in the electricity sector begin with no more than 50% of allowances provided freely to deliverers based on historical emissions. Under this proposal, the average annual allowance level would approximately equal the average level of "required" compensation among the studies considered by Harrison et al (2007). This level would substantially offset the costs faced by deliverers during the crucial early years of the cap and trade program, allowing entities time to adjust production and identify cost-effective mitigation strategies.

If this approach is pursued, the amount of emission-based allocation should decline each year and cease altogether within a few years. As a starting point, Staff recommends that the emission-based allocation decline 10% per year and completely end in year 6 (see Table 2). This recommendation would mitigate the windfall profit issues associated with long-term emission-based allocations.

Table 2. Suggested Transition Schedule if Emission-Based Allocation is Adopted

Year	Percent of Allowances Allocated based on Emissions	Percent of Allowances Allocated by Auction or Output-Based
2012	50%	50%
2013	40%	60%
2014	30%	70%
2015	20%	80%
2016	10%	90%
2017 +	0%	100%

Under this approach, California would need an alternative method or methods for allocating those allowances not distributed based on historical emissions. Staff recommends that the State consider output-based allocations or auctioning as possible means of distributing allowances. Both output-based allocation and auctioning avoid the potential for large-scale additional profits accruing to independent deliverers. The elements of these allocation systems are described below in Section 6 and Section 7. In the Interim Opinion, the Commissions recommended that at least some portion of allowances should be auctioned. Thus, if any output-based allocation were to be used, allowances would be allocated by three different methods in the early years of the program. The use of three different allocation methods would increase the administrative complexity of the program.

Staff finds the need for a rule on plant closures and new entrant accommodations to be unnecessary under this proposal. While such rules have been adopted by most Member States in the EU, the low initial share and decline in emission-based allocation under this proposal would reduce the equity and competition concerns that a closure rule and new entrant accommodation are aimed at addressing. The large percent of auctioned or output-based permits provide new entrants with an opportunity to meet their allowance needs. While equity concerns are the most frequently cited need for ending historically-allocated allowances when a plant ends production, these concerns would be mitigated by the fact that emissions-based allocations would be gradually phased out after 5 years.

6. Output-Based Allocation

6.1 Mechanics

With output-based allocation, allowances would be distributed freely to eligible deliverers based on the MWhs delivered to the California grid. As discussed previously, staff recommends that the allocation be updated periodically if this approach is adopted. In contrast to the emission-based approach, continued allocation of output-based allowances would depend on continued deliveries of electricity. Each eligible unit of power delivered to the grid would receive allowances at some rate per MWh such that the sum of allowances allocated equals the cap.

Output-based allocation of a fixed number of allowances is distinguished from a 'benchmarking' allocation system. This paper recognizes an output-based system as one that allocates a set amount of allowances to deliverers in proportion to their deliveries in a previous year. Under a benchmarking system, each unit of eligible generation would receive allowances at an administratively-set allowance rate.

While these systems appear similar, one key difference between these allocation methods is that a benchmarking system lacks a firm cap. A benchmarking system utilizes an allocation rate that is set administratively based on projected load, forecasted deliveries of hydropower, and the estimated production from GHG-emitting resources needed to meet load. Unanticipated variations in production from emitting facilities would result in the total allowance levels fluctuating higher or lower than the intended cap. State regulators could attempt to match the cap on average by adjusting future emission rates higher or lower, depending on the excess or shortage in total allowances issued.

In order to operate under a firm cap, output-based allocation must instead use a prior year's delivery levels to determine the allowance allocation for each deliverer. The following example, shown in Table 3, illustrates how an output allocation could function in 2012 where total generation is delivered by 3 entities – Deliverer A, Deliverer B, and Deliverer C. In this case, 2012 allowances are allocated based on deliveries in 2011. Deliverer A delivered 50% of the electricity in 2011 and therefore receives 50% of the allowances for 2012. Deliverers B and C receive smaller portions of the total allowances in 2012, 37.5% and 12.5%, respectively. These allowance portions are multiplied by the 2012 allowance cap to determine the total allowances received by each firm.

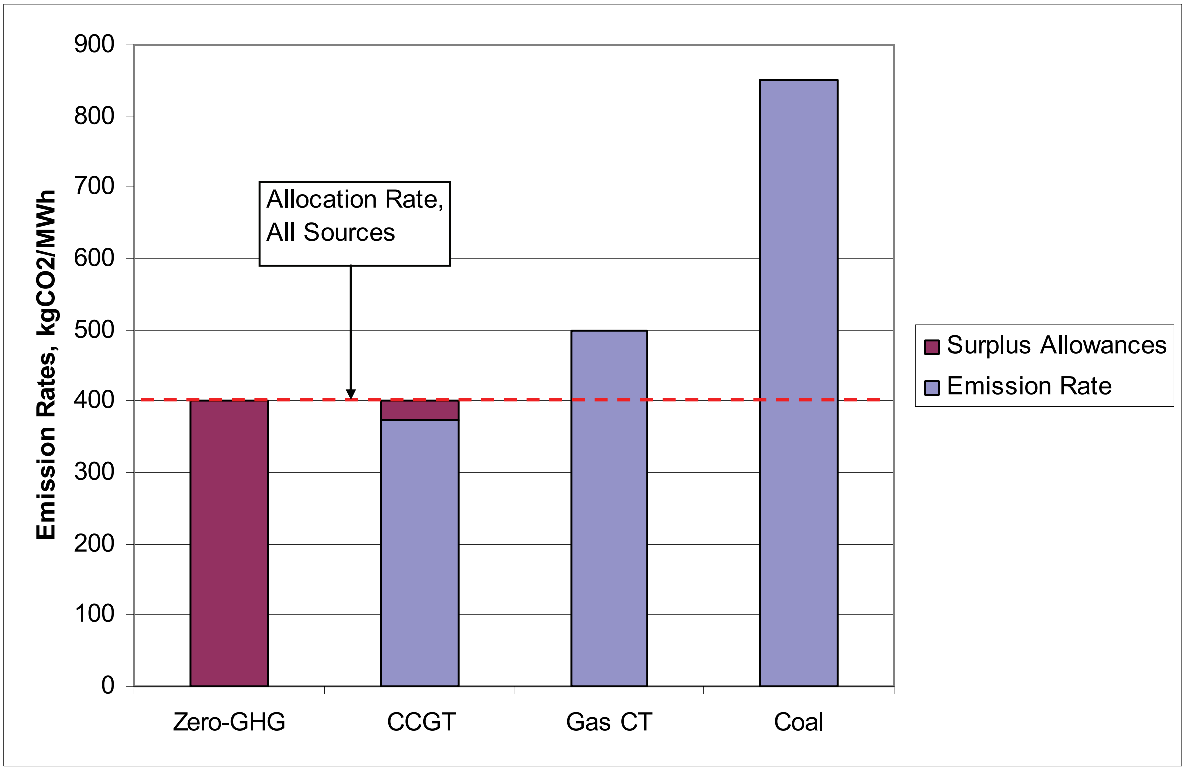
Table 3. Hypothetical Output-Based Allocation to Deliverers

	Deliveries in 2011, Million MWh	Share of 2011 Deliveries, Million MWh	2012 Allowances Received, Millions of Tons (Cap = One Hundred Million Tons)
Deliverer A	100	50%	50
Deliverer B	75	37.5%	37.5
Deliverer C	25	12.5%	12.5
Total	200	100%	100

6.2 Analysis of Pure Output-Based Allocation

Under a pure output-based allocation, all deliverers would receive allowances based on power delivered to the grid. In this example, we use allocation of a fixed pool of allowances based on deliveries in a prior year. Deliverers would receive freely allocated allowances in one period in proportion to their deliveries to the California grid in a previous period. On an annual basis, the allowance level would be updated to reflect changes in the total generation levels as well as the changes in the cap. As the cap declines, the amount of allowances per unit of generation would also decline, assuming the power delivered does not decline as well.

Figure 4. Example of a Pure Output-Based Allocation Method



In this formulation, for each MWh delivered to the grid, a deliverer would receive the same number of allowances. Using 2004 as an example, California generators produced approximately 195 million MWh and gross imports totaled another 98 million MWh, yielding 293 million MWh generated for deliveries to the California grid. According to the inventory approved by ARB on December 6, 2007, total GHG emissions in 2004 associated with in-state generation and gross imports were approximately 117 million metric tons carbon dioxide equivalent ($MMTCO_2e$).[19] If the electric sector had a cap with an allocation that matched emissions in 2004, allowances would have been allocated at the average emission rate of 0.4 metric ton CO_2e per MWh. As Figure 4 shows, generation delivered from simple cycle combustion turbines and coal-fired sources would be short of allowances for each MWh delivered. Deliveries from efficient combined-cycle gas turbines and zero-emitting resources would receive surplus allowances for each MWh generated.

Unlike emission-based allocation, output-based allocation does not result in a large transfer of wealth from customers to deliverers. Under an output-based allocation, deliverers will find that they have an incentive to increase their delivery levels. Higher delivery levels ensure that deliverers will continue to receive valuable allowances in future years. In order to maintain sales, deliverers are likely to find that they cannot pass on the entire value of their allowances.

Consider the example of deliveries from the power plant discussed in Section 5.2. Because it may be more intuitive to understand, a benchmarking allocation method is used for purposes

[19] The values for both generation and emissions include electricity consumed for on-site use at CHP facilities.

of this example. The plant emits 0.5 metric tons of CO_2e for every MWh generated and has a marginal cost of $70 per MWh. Assume further that the benchmark rate is also 0.5 metric tons of CO_2e per MWh. Instead of receiving free allowances in perpetuity, under a "benchmarking" system the deliverer would only receive allowances equal to 0.5 metric tons CO2e for every MWh it delivers. If the plant produces and the market clears at $80 per MWh, the plant will earn $10 per MWh. There would be no allowance cost in this example since the plant's emissions will exactly be covered by the amount of the allocation it receives. In contrast to the emission-based example, if the plant does not produce electricity, it earns nothing because it would not receive any allowances to sell. The firm would not have an incentive to shut down or reduce generation, since it loses its allocation if it does not produce. Under a fixed-cap output-based allocation, the same incentives apply. Passing on the entire value of the allocation would risk diminishing its sales, which could be lost to lower-priced competition or reduced consumer demand. In this way, output-based allocation results in lower prices than emission-based allocation.

Numerous research studies support the conclusion that output-based allocation results in lower energy price increases relative to other emission-based or auction allocations.[20] Studies by Burtraw et al. (2001 and 2005) and Fischer and Fox (2004) indicate that output-based allocation results in only slight electricity price increases, significantly below the price increases under emission-based allocation and auctioning (assuming there is no revenue recycling). The Burtraw et al. 2001 model of a national cap and trade program found that output-based allocation resulted in the lowest electricity prices when compared to historical emission-based allocation or auctioning (again, assuming no revenue recycling). The 2005 study conducted for the Regional Greenhouse Gas Initiative (RGGI) region also found relatively low electricity prices under an output-based allocation. By incentivizing a higher level of consumption, these lower prices come at the expense of total economic efficiency (see Section 2.1). Allowance prices are higher as a result.

In its analysis of the pure output-based allocation method, staff identified the following impacts:

- Output-based allocation results in lower customer costs than emission-based allocation. Upward price pressures are mitigated by providing incentives for low emitting resources to increase production and deliveries to the grid.

- A pure output-based allocation would likely result in a large redistribution of money from customers of retail providers that depend on high-GHG sources of power to less GHG-intensive retail providers.

- A pure output-based allocation system can be administered with a simple formula and straightforward reporting requirements.

- A pure output-based allocation easily accommodates new market entrants.

[20] Note that these studies did not consider the possibility of recycling auction revenues back to retail providers.

6.3 Variations on Output-Based Approaches

Output-based allocation may be modified in several ways to meet various policy goals. We discuss some of these variations below.

6.3.1 Benchmark versus Cap

As described above, output-based allocations can be awarded based on a set rate to each unit of electricity delivered to the grid. This option effectively eliminates a hard cap and allows total emissions to fluctuate annually. Alternatively, output-based allocations can be awarded under a set cap level based on past years' production levels.

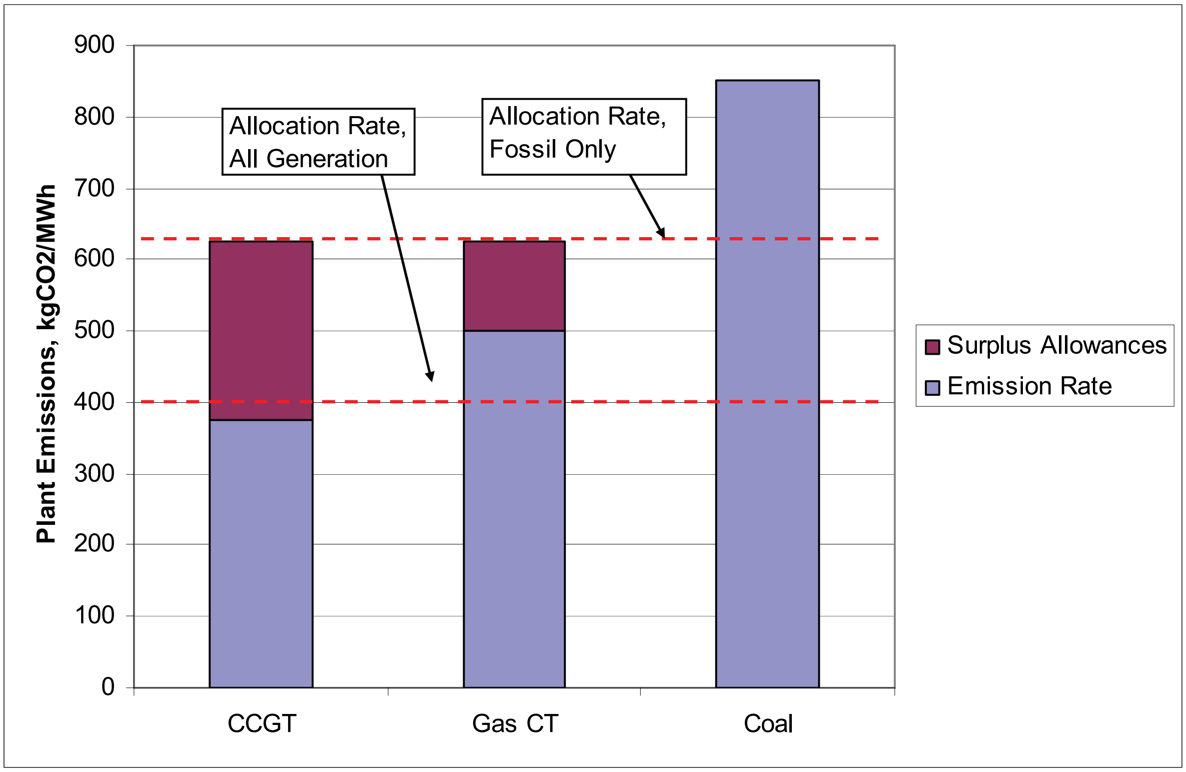
6.3.2 Updating Methodology

When a fixed cap approach is used, output-based allocation requires a methodology for determining the frequency of updating and the length of the baseline period. Updating can occur annually, with the shares of allowances allocated to each deliverer changing each year, or the updating period can last several years, with allowances issued based on the same baseline period for several years. The baseline period can be a single year, or an average of several years' deliveries can be used. More frequent updating helps support new entrants by providing new deliverers with free allowances after only a short period of operation. Updating on a rolling multi-year period could provide more stable allowance allocations to deliverers, but would also delay allowance allocations to new entrants.

6.3.3 Restriction of Generator/Deliverer Eligibility

Output-based allocation can exclude certain non-emitting deliverers – such as nuclear or hydro generation – or limit the allocation to emitting fossil fuel deliverers only. Under these scenarios, allocations per unit of fossil fuel generation will increase, augmenting the incentive to deliveries from natural gas and reducing the cost of compliance for coal-fired generation, compared to allocation to all sources. This is depicted in Figure 5.

Figure 5. Example of a Fossil-Only Output-Based Allocation



Limiting allowance allocation to deliveries of fossil fuel generation would eliminate some allocation uncertainty for GHG-emitting deliverers. Some non-emitting deliverers – such as hydropower facilities – are subject to large fluxes in annual generation. Under an all-generation allocation, these annual generation changes could result in large, unpredictable changes in annual allowance allocations to GHG-emitting deliverers. Limiting allocation to fossil fuels would reduce the impact of generation changes from non-emitting deliverers, providing more certainty to generators regarding future allocation levels.

Limiting output-based allocation to fossil fuels presents some administrative challenges. Unspecified power would need to have an underlying resource mix identified in order to determine eligibility for allowances. The inability to identify the resource mix of some imports could give electricity importers an incentive to contract shuffle, shifting low-carbon fossil fuel generation into the state, to replace generation from non-emitting resources, in order to receive allowances. In the process of estimating supplier-specific or regional default emission factors, some identification of the underlying resources will be necessary. This information could be used to allocate allowances to unspecified power. For example, if future analysis of the resource mix used to provide power to California from the Northwest determined that on average, 30% of the MWhs were generated from fossil fuel sources, every unspecified MWh from the Northwest would count as 0.3 MWh for purposes of allocating allowances in proportion to recent generation.

Fossil fuel-based allocations place renewable development at a competitive disadvantage. Since gas-fired generation would receive revenue from the surplus allowances received, the price of gas-fired generation would tend to decline. Price increases of fossil fuel generation would help support renewable development, as most renewable energy sources are more costly than fossil fuel generation. By diminishing energy price increases, output-based allocation can act to reduce incentives to develop renewable energy. Modeling results by Burtraw et al. (2001, 2005) support this conclusion.

6.3.4 Differentiated Allocation by Fuel Type

Output-based allocation methods can also be designed to distribute allowances on a differentiated basis among fuel types. This can be done using several categories of fuel and technology type; however, to simplify the analysis we explore a differentiation based only on two fuel types – gas and coal. Administration of a fuel-differentiated output-based allocation method would be more complex than a non-differentiated method because the allocation to one deliverer will depend not only on the total quantity of generation (or emitting generation) but also on the relative proportions of gas and coal-fired generation delivered to the California grid.[21]

With the additional need to allocate allowances to MWhs from different fuel types at non-uniform rates, some sort of weighting factor would need to be developed for higher-GHG sources. This weighting factor might be based on the ratio of the emission rate of an efficient coal-fired plant to that of an efficient gas-fired plant. An example of how this would work in practice is shown in Table 4 below. In this example, there are 100 $MMTCO_2e$ of allowances allocated for the electric sector in 2012. Total fossil-fired generation in 2011 was 150 million MWh, with 100 million MWh from gas-fired sources and 50 million MWh from coal-fired sources. The weighting factor for coal-fired electricity is 2, based on the fact that coal plants emit approximately one metric ton of GHGs for every MWh produced and gas plants emit approximately 0.5 metric ton per MWh.

Table 4. Fuel-Specific and Undifferentiated Output-Based Allocation to Fossil-Fired Generation

Generation Fuel Type	Deliveries in 2011, million MWh	Share of 2011 Deliveries	2012 Allowances Received, Million	Weighted Deliveries in 2011, million MWh	Share of 2011 Weighted Deliveries	2012 Allowances Received, Million
Gas-Fired	100	66.7%	66.7	100	50%	50
Coal-Fired	50	33.3%	33.3	100	50%	50

In this example, assuming that 2012 deliveries are similar to 2011 deliveries, an undifferentiated allocation would result in deliverers of coal-fired generation having to purchase approximately 17 million allowances from deliverers of gas-fired generation. Under the fuel-specific allocation, deliveries from gas and coal generation would, on average,

[21] In reply comments to the October 15, 2007 ALJ ruling requesting comments on allocation issues, Kenneth Johnson provided a detailed overview of how fuel-differentiated output-based allocations can be implemented. Although his explanation is couched in a broader method that employs auctioning with output-based refunding, the fundamental principles still apply.

receive very near the number of allowances needed for compliance. The consequences of these two methods have interesting implications for cost to consumers and transfers among customers of different retail providers. The additional revenue that gas deliverers would receive from coal deliverers in the uniform allocation would allow gas deliverers to sell their output at a reduced cost. This would reduce consumer costs for customers of retail providers that are largely dependent on gas generation, but would raise consumer cost for customers dependent on coal-fired generation. The fuel-specific allocation could be designed to eliminate these transfers.

6.4 Preferred Output-Based Approach

Based on its analysis of the pure output-based allocation, staff recommends that an output-based allocation be limited to electricity delivered from fossil fuel generation sources. An 'all-generation' output-based allocation would provide a large amount of valuable allowances to deliverers of power from existing nuclear, hydropower and other zero-GHG plants. Allocating allowances to these entities would provide no clear program benefits but would generate large amounts of revenue for these entities when they sell their allowances. Deliverers dependent on fossil fuel-generation would bear the cost of the payments, as they would need to purchase all or some of the allowances from these entities. This would produce a sizable transfer of wealth from customers of high-GHG retail providers to customers of low-GHG retail providers. An allocation only to fossil fuel-generated electricity delivered to California eliminates the distribution of revenue to non-emitting deliverers and reduces the compliance cost for deliverers of fossil fuel-generated electricity. However, a variation on this approach that warrants additional analysis is the inclusion of incremental generation from new renewable sources in the eligible generation. This approach would help counter the competitive disadvantage that renewables face under a fossil fuel-only output-based allocation method (Burtraw, Palmer and Kahn 2005).

If an output-based allocation limited to fossil fuel generated electricity is adopted, staff recommends an initial fuel-specific output-based allocation as described in Section 6.3. Differentiating the allowance rate between different fossil fuel technologies would reduce the redistributive outcomes among the customers of different retail providers. An output-based allocation granting allowances equally to deliveries from all fossil fuel generation on a non-fuel specific basis would likely result in deliverers of coal-fired generation purchasing large quantities of allowances from deliverers of gas-fired generation (or from an auction or other sectors). Since deliverers of gas-fired generation would receive surplus quantities of allowances, the price of deliveries from gas-fired generation would decrease (Burtraw, Palmer, and Kahn 2005). Therefore, retail providers that depend on a high ratio of deliveries from coal-fired generation relative to deliveries from gas-fired generation would have to pass through the embedded cost of allowances while retail providers that depend on a large ratio of gas-fired generation would benefit from lower electricity prices. Whether direct (deliveries from utility-owned generation) or indirect (deliveries from independent generation), a transfer among the customers of different retail providers would occur.

The fuel-specific output-based allocation faces administrative challenges similar to the uniform fossil fuel-only allocation related to power from unspecified sources. A fuel-differentiated output-based allocation would require detailed analysis of deliveries from unspecified power during each baseline period, to identify the sources of the underlying generation.

Like other output-based methods, this allocation method would not inhibit new entrants from entering the market.

Staff recommends that, if an output-based allocation is adopted, it begin by allocating the majority of allowances based on output and transition over time to a 100% auction-based allocation. A suggested transition schedule is shown in Table 5. The transition to a 100% auction system would allow carbon markets to mature without subjecting consumers to potentially large price fluctuations in the early years of the cap-and-trade program. Transitioning would also allow the State an opportunity to develop sufficiently robust market oversight processes and allow deliverers and retail providers additional time to transition their resource mixes to reflect the new cost of carbon emissions.

Table 5. Suggested Transition Schedule from Output-Based Allocation to Auction

Year	% Allowances Issued on Output Basis	% Allowances Issued by Auction
2012	90%	10%
2013	80%	20%
2014	70%	30%
2015	50%	50%
2016	30%	70%
2017	10%	90%
2018+	0%	100%

If the program does not transition to a large share of auctioning within a few years, it will be important to decrease the weighting factor for deliveries from coal-fired generation. In the longer term, the weighting factor raises significant efficiency concerns by shielding high-GHG sources of generation from the cost of pollution emitted, either through an opportunity cost or real cost of purchased allowances.

7. Auctioning

7.1 Mechanics

If allowances are auctioned, there is no need to determine a method of distributing the allowances to the deliverers required to have them. Allowances would be bought by regulated entities as needed in the auction or in the secondary market. In this paper, we do not yet delve into the finer points of auction design. If ARB decides to implement a cap-and-trade system that includes auctioning of some portion of the allowances, the Commissions may wish to assist ARB in the future by analyzing and providing recommendations to ARB on electricity sector-specific elements of auctions and ways to mitigate potential market manipulation.

For purposes of this paper, we assume that any actual auction that comes to pass would be conducted either by ARB or an auction agent under contract to and oversight of ARB. We do not propose that any entity in the electric sector have a role in conducting auctions, should they occur under the AB 32 framework.

Beyond this, we do address one other aspect of auction design that we believe merits early consideration. This relates to the fear that some parties have expressed that parties with financial interests could buy large amounts of allowances and hoard them in order to drive up future prices or otherwise "game the system." The RGGI auction design report concluded that inherent market features coupled with some straight-forward design features should be sufficient to prevent market manipulation. For example, Holt et al. (2007) suggest that no one entity should be allowed to purchase more than 33% of the allowances in any one auction. In the proposed RGGI design, the allowances for a given year would be auctioned over eight rounds with 12.5% auctioned in each round. No single entity would be able to purchase more than approximately 4.3% of a single vintage in any particular round. Attempts to hoard allowances would be detected before a large share of allowances could be acquired by any single entity, and appropriate steps could be taken to limit a party's future participation. The RGGI auction design report cites two advantages of open auctions: greater participation in the auctions encourages liquidity in the secondary market and provides a measure of protection against collusion or other manipulative behaviors.

If further analysis suggests that the California market is susceptible to manipulation, ARB may decide to limit auction participation, at least initially. In the interest of caution, ARB could conduct separate rounds of auctions in which the first lot is available only to entities with a compliance burden and a subsequent lot is available to all parties. Alternatively, ARB may wish to limit entities representing financial enterprises with no compliance obligation to a lower purchase limit than entities with a compliance obligation. Staff does not have enough information at this time to make a specific recommendation.

Instead of the auction mechanics per se, we focus in this paper on the disposition of the auction revenues. The Commissions state in the Interim Opinion that the majority of auction proceeds from allowances in the electricity sector should be used in ways that benefit electricity consumers:

> "As a starting principle, it is important that any policy for distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit consumers in the energy sectors directly. This is because energy sources such as electricity and natural gas are vital commodities. Thus, we believe special focus is warranted for allowance allocation policy in the energy sectors."[22]

There are a variety of ways in which the auction revenues from the electricity sector could be preserved for the benefit of consumer purposes in the sector, either to aid in GHG reductions/mitigation or for consumer bill relief. One option would be to allocate allowances directly to retail providers of electricity, on behalf of their consumers, on some basis, but require those retail providers to offer up their allowances during the auction. In this way, retail

[22] D.08-03-018, p. 8.

providers would receive the proceeds from auctioning of their allowances directly, with the funds raised to be used to benefit their consumers. As with the free allocation methods described earlier in this paper, allowances could be granted to retail providers on a variety of bases, including historical emissions (based on their resource portfolio mix) or sales of electricity to consumers.

The advantage of this type of approach would be in the efficient distribution of auction revenues directly to retail providers on behalf of their consumers. This is the approach that most RGGI States are taking to distribution of allowance value.[23] Note that staff is not proposing that retail providers conduct the auction; as stated above, we assume that the auction itself would be run by ARB or its agent. Retail providers would simply be required to offer up their allowances at auction in order to receive the revenues once the auction is conducted. Retail providers who are also deliverers would also need to purchase allowances in the same auction to cover the emissions associated with their electricity deliveries.

Another option is for no actual allowances to be allocated prior to the auction, but instead for retail providers to be granted auction revenue rights on some basis entitling them to the proceeds from the auction. This is the option described for illustrative purposes in this paper.

We propose that the majority of revenues from the electricity sector's share of auctioned allowances be placed in a reserve account for retail providers.[24] We note that for retail providers with self-owned fossil-fired generation, particularly fully resourced utilities, payments for allowances successfully purchased at auction may present unproductive up-front cash flow problems as those same entities would be entitled to receive revenues from the auction as well. If the retail provider were actually required to submit payment for the entire block of allowances purchased, this could constitute a substantial payout for retail providers that are fully resourced, particularly those still dependent on coal facilities. This payment for allowances followed by the return of auction revenues to such retail providers from the reserve account would result in unnecessarily large payments by and to these utilities. Therefore, we recommend that deliverers that are also retail providers only pay for the net difference between their allowances purchased at auction and the revenues returned via their ARRs.

[23] While the RGGI model rule requires a minimum of 25% of allowances be auctioned for consumer purposes, the majority of states have stated an intent to auction 100% of allowances.

[24] See Title IV, Subtitle B of the "Lieberman-Warner Climate Security Act of 2007" (S.2191) reported from the Senate Committee on Environment and Public Works December 5, 2007 for an example of a proposed "carbon trust" established to manage auction revenues in an account separate from general revenues. It may be necessary for ARB to seek additional authority from the Legislature to establish a similar fund for the State of California.

Table 6. Example of Net Payments or Receipts at \$20 per Metric Ton CO_2e

	Base Period Emissions, $MMTCO_2e$	Share of Base Period Emissions	2012 Emissions, $MMTCO_2e$	2012 Allowance Payments, Million \$	Revenue from ARRs, Million \$	Net Receipt/ Payment, Million \$
Utility A	45.0	50%	50.0	1,000	1,000	0
Utility B	22.5	25%	27.5	550	500	-50
Utility C	22.5	25%	22.5	450	500	50

Examples of how the net payments would be calculated are provided in Table 6. In this example, all utilities are assumed to be fully resourced and vertically integrated. In this example, the total allocation to the electric sector covers the sector's emissions in 2012 and the auction revenues are returned to retail providers on a historical emission basis (described below). The emissions of both Utility A and Utility B have grown since the base year, whereas Utility C has managed to keep emissions constant. Since Utility A's emissions have grown at the average rate, its share of emissions in 2012 is the same as its base year share. Utility A makes no payment in 2012 because the \$1 billion in ARRs match the \$1 billion for allowances to cover its emissions. Utility B's emissions have grown faster than the average rate, so its emission-based ARRs do not fully cover its need for allowances. The net payment by Utility B is \$50 million. Utility C's emissions have not grown, and it receives a net payment of \$50 million.

7.2 Rationale for Retaining Auction Revenue in the Electricity Sector

Staff suggests that there are three persuasive reasons for retaining a large share of any auction revenues for consumer benefit in the electricity sector. First, electricity consumers in California are currently paying, and will continue to pay, a variety of public goods charges that are directly climate related. As stated in the Interim Decision, the principal sources of direct GHG reductions in the electricity sector in the near term come from investments in energy efficiency and renewables. Retail providers are currently the principal service providers for these investments. Since ambitious energy efficiency and renewable goals are mandatory for California's retail providers, it would be redundant to have retail providers paying for mandated reductions and the total embedded allowance cost of purchasing or generating power. As the absolute minimum, auction revenues sufficient to offset the total expenditures expected for these programs should be retained within the sector, to be expanded as additional cost-effective measures are identified.

The second reason is that, as stated in the Interim Opinion, electricity is a vital commodity. The average retail rate in California is roughly 40% higher than the average national rate. Electricity costs are considered regressive by some because lower-income consumers spend a higher proportion of their income for electricity compared to higher-income consumers. As GHG emissions costs put upward pressure on retail rates, lower-income households may bear a disproportionate burden; thus, some bill relief is desirable, especially for low-income households. If GHG costs were not at least partially dampened, they may induce some degree of leakage because businesses might choose to relocate elsewhere. Leakage would undermine the goals of the GHG program because real reductions in GHGs would not occur. Thus, staff believes that some portion of the allowance value should be allocated to retail providers for bill relief.

The third reason is that most customers are served by regulated utilities which have extensive public oversight from either the Public Utilities Commission or their local governing boards. Such firms cannot unilaterally pass GHG related benefits to their shareholders or use them to invest in other types of commerce. Regulated entities can be held accountable for spending their funds in a manner directed to meet the goals and timelines of AB 32.

Beyond retaining auction revenues within the electricity sector, it would be possible to return some of the revenues to the particular retail provider from which they came. These funds could be required to be used for energy efficiency, renewable, and other emissions reduction programs. This approach has the advantage of minimizing any transfers among customers of retail providers.

It is also important to understand that in a market-based system, the fact that a retail provider may spend more money on GHG allowance costs (whether directly or embedded in the power it purchases from the market) than it receives in recycled revenues does not necessarily mean that it has suffered from being in a cap-and-trade system. If its own cost of reducing emissions is greater than the price of allowances, a retail provider would actually best serve its customers by purchasing more allowances than the number of ARRs assigned to it. The example below describes a fully-resourced utility, but the same reasoning applies to other retail providers as well.

Assume that a utility is emitting 100 tons of GHGs in 2012. This utility has received an allocation of 100 allowances (or ARRs for 100 allowances) in 2012, which precisely matches its emission level in the first year of the program. The number of allowances it receives will decline to 80 allowances by 2020. It is now 2017, and allowances are trading around $50 per ton. This utility determines that it will be able to reduce emissions to 85 tons by 2020 at a cost of less than $50 per ton, but reductions from 85 to 80 tons will cost $70 per ton. This utility has a choice to make. Should it try to stay within the allocation that it will be given by the State in 2020? It could, but that would cost its ratepayers an additional $100 compared to reducing its GHG intensity only to 85 tons and buying 5 allowances. In this example, the utility may decide to purchase allowances beyond its allocation, but it is better off by being in a cap-and-trade system than if it were given a cap with no trading allowed. (Conversely, if this utility had lower-cost reduction options and could achieve reductions below 80 tons of GHGs for less than $50 per ton, it would benefit from receiving more money from auction revenues than it spends on allowances, which it could not do if there were no cap-and-trade program.)

As long as the State assigns ARRs to retail providers according to a schedule of emission reductions that are reasonably attainable, no single retail provider will be disadvantaged by participating in a cap-and-trade system compared to an alternative scenario in which individual caps are established. If one retail provider finds that reductions are more expensive than anticipated, and allowances are trading at a price that is less than its cost of abatement, it has the opportunity to benefit from the presence of the market and buy additional allowances, thereby saving its customers money.

7.3 Analysis of a Pure Auction Method

The Interim Decision does not endorse starting with 100% auctioning, and staff does not recommend such an approach. However, we present it here to illustrate the features of an auction method, before that method is adjusted to take into account California's needs and priorities. It is difficult to describe the implications of theoretically beginning the program with 100% auctioning without considering the use of the revenues generated. For purposes of illustrating a "pure" auction method, we first assume that *none* of the auction revenue is refunded to retail providers for customer benefit. How would this approach fare using the evaluation criteria?

- Auctioning of allowances without refund of auction revenues to retail providers would increase consumer costs substantially because deliverers would have to recover the cost of the allowances in their bid prices, contracts, or retail rates. The expenditures for allowances would constitute a transfer from deliverers (and ultimately consumers) to the State. Additionally, deliveries from low-GHG resources that are not owned by California retail providers (such as imports of low-GHG power from the Northwest) would benefit from some windfall profit due to the increase in wholesale prices. Choices about how auction revenues are spent can reduce the total social cost of the program. For example, auction revenue could provide additional economic efficiency gains if the revenues are used either to offset distortionary fees or taxes or to make public investments with a high rate of return. (Smith and Ross 2002; Roland-Holst 2006)[25] Since, in this example, none of the auction revenues would be returned to retail providers, no direct transfer among customers of retail providers would occur. However, if the State spends the auction revenues in a way that provides benefits relatively evenly across the state, an indirect transfer from customers of high-GHG retail providers to customers of low-GHG retail providers does occur. Assuming this to be the case, large redistributive impacts among retail providers' customers would be likely.

- Without consideration of administrative requirements associated with the return of auction revenues to retail providers, auctioning is an administratively simple method because no baseline needs to be calculated, and load migration is not an issue.

- Auctioning easily accommodates new entrants.

[25] As discussed previously, stakeholders are concerned that any auction design would need to be carefully designed to protect against market manipulation. This issue will need to be addressed by ARB if it makes a determination in the scoping plan that an auction is appropriate.

7.4 Variations on Auctioning with Revenue Retention

We now examine two methods of allocating auction revenue to retail providers that have been proposed in this proceeding, emission-based allocation and sales-based allocation.[26] This recycling would be accomplished by assigning ARRs to the retail providers.

Table 7 provides an illustrative example of how these two approaches might work in practice. In this example, it is assumed that ARB has allocated 100 million 2012 vintage allowances for the benefit of the electric sector, representing roughly the projected level of emissions in that year. The auction clears at $20 per allowance, yielding $2 billion in auction revenue to be allocated among retail providers. Using the emission-based allocation of revenues, Utility A, whose power purchased or generated to serve its customers emitted half of the base year emissions, would receive half of the revenues, or $1 billion. The other two utilities, each of whose power emitted one-fourth of the total base year emissions, each receive $500 million.

Table 7. Revenue Redistribution, One Hundred Million 2012 Vintage Allowances Auctioned at $20 per Metric Ton CO_2 Equivalent

Retail Provider	Base Year Emissions, $MMTCO_2e$	Share of Base Year Emissions	2011 Retail Sales, GWh	Share of 2011 Retail Sales	Rev, Emission-Based ARRs, Million $	Rev, Sales-Based ARRs, Million $
Utility A	45.0	50%	60,000	30%	$1,000	$600
Utility B	22.5	25%	50,000	25%	$500	$500
Utility C	22.5	25%	90,000	45%	$500	$900

Using a sales-based approach, each utility would receive the revenues in proportion to a previous year's sales. In this example, a retail provider receives $10 from auction revenues for each MWh of load served. Because the emission rates associated with the power used to serve each retail provider's load differ significantly, the two methods of assigning ARRs produce widely divergent results. Because Utility A's share of 2011 sales was only 30%, it would only receive $600 million. Utility B would receive the same amount of revenue under either approach, and Utility C would receive $400 million more under the sales-based approach.

A sales-based allocation of ARRs in 2012 might lead to a large redistribution from coal-dependent retail providers to less GHG-intensive retail providers. In fact, the effect is likely to be similar to a pure output-based allocation. Coal-dependent retail providers might be saddled with rate increases due to GHG allowance costs in the first year of the cap. Assigning ARRs on the basis of retail providers' historical emissions would produce strikingly different results, with little potential for wealth transfer among customers of different retail providers at the beginning of the cap-and-trade program.

[26] In comments NRDC/UCS indicated allocation of allowance value on a sales basis could inadvertently discourage energy efficiency activity (Opening Comments to the October 15, 2007 ALJ Ruling). As a remedy, NRDC/UCS propose that any sales-based method should also allocate allowance value to verified energy efficiency savings. Thus, "nega-Watt hours" would receive an allocation of auction revenues on an equal basis with actual MWhs sold. Allocating ARRs for energy efficiency may complicate the GHG program although more analysis of the incentive effect would need to be conducted before staff can provide a firm recommendation on this aspect of ARR allocation.

7.5 Preferred Auction Approach

In light of the consumer cost and redistributive impacts of a pure auction approach, staff developed a "preferred" auctioning scenario for discussion purposes. It involves auctioning 75% of allowances from the outset of the program. The remainder of allowances could be allocated to deliverers on an emission or output basis or used for purposes such as rewarding early voluntary action. As discussed above, this option is predicated on the condition that the majority of the allowance value is recycled to retail providers for the benefit of end users. Redistribution of allowance value to retail providers could be accomplished by assigning ARRs to retail providers.

The discussion above illustrates that there could be large distributional effects that might arise from allocating ARRs on a sales basis. Staff concludes that this approach would constitute an unacceptable transfer from the customers of historically coal-dependent retail providers to other California customers. In this straw proposal, staff proposes that ARRs be assigned at the start of the program on a historical emission basis.

When the 2012 allowances are auctioned, the revenues from the auction would be distributed to the retail providers in proportion to their emissions from their entire portfolio in a base period. Auction revenues would be distributed on this basis as a proxy of the likely impact on the cost to retail providers' customers. In reality, for retail providers that purchase electricity to cover most of their loads, the cost impact would be determined by the marginal generators that supply their power.

Over time, as retail providers are able to reduce their dependence on GHG-intensive power, the distribution of ARRs to retail providers could be transitioned to be based increasingly on sales. Given the information available at this time, it appears that approximately half of the ARRs could be allocated on a sales basis by 2020. A higher or lower proportion may be warranted based on further analysis. This will depend on conditions such as the degree to which access to hydropower or nuclear facilities gives some retail providers a capacity to deliver low-GHG power to their customers that is not available to other retail providers. Progress in developing and commercializing carbon capture and sequestration technology is another factor that might be taken into consideration.

Another option worthy of consideration would be to allocate ARRs on the basis of "net load"—subtracting out load or sales that are served by legacy investments in nuclear or large hydroelectric facilities.[27] This proposal may merit consideration as one approach that could guide the transition schedule away from emission-based ARR allocation.

Table 8 depicts one possible schedule for transitioning from emission-based assignment of ARRs to sales-based ARRs. Under this schedule, the allocation of ARRs would transition slowly from a historical emission basis in the early years of the program, with the rate accelerating to a sales basis in later years. The slower rate of transition in the early years

[27] This concept was introduced by Jim Lazar, a consulting economist for the City of Burbank, during comments at the November 5, 2007 joint Commissions' workshop on allocations in the electricity sector. Mr. Lazar defines this loosely as the "load minus that that's served by old, low-cost, noncarbon resources; big hydro and perhaps nuclear." See allocation workshop transcript, p. 137.

reflects the long lead time needed for investment in renewable energy and any transmission upgrades needed to deliver the power to loads. Additionally, some of the existing contracts that California retail providers have with out of state coal plants will not expire until several years after the implementation of the cap in 2012, making it difficult for coal-dependent retail providers to sever their reliance on these plants in the early period.

Table 8. Suggested Straw Proposal Transition Schedule of ARR Distribution

Allowance Vintage	Emission-based ARRs	Sales-based ARRs
2012	100%	0%
2013	95%	5%
2014	90%	10%
2015	85%	15%
2016	80%	20%
2017	70%	30%
2018	60%	40%
2019	50%	50%
2020	50%	50%

A transition schedule such as the one depicted in Table 8 could produce the "glide path" that some have discussed to encourage retail providers to transition away from reliance on carbon-intensive resources over time, while also regulating emissions directly at the deliverer level.

In sum, staff finds that the preferred auction design with initial allocation of ARRs on a historical emission basis results in low consumer cost and minimal redistribution among retail providers. Note that there is a trade-off between addressing consumer cost increases with emission-based ARRs and administrative simplicity. Setting up an emission-based ARR system would necessitate the creation of a historical baseline, similar to the process required for emission-based allocation to deliverers. However, setting baselines for retail providers would be further complicated by the need to assign generation to loads. This preferred design would be more administratively complex if load migration among ESPs or from ESPs to LSEs is accounted for. Additionally, some accommodation for retail providers with rapidly growing customer bases might also need to be evaluated.

8. Summary of the Allocation Methods

Table 9 summarizes how the different allocation methods described in this paper would perform compared to the identified evaluation criteria. For each basic method, both the pure version and the staff-preferred version are shown. Checks indicate that the method would generally perform well according to that criterion while an "X" indicates that it would perform relatively poorly.

Table 9. Summary of Evaluation Criteria Applied to the Allocation Methods

Allocation Method	Consumer Cost	Transfers among Retail Provider Customers	Admin Simplicity	New Entrants
Pure Emission-Based	✕/✓ [a]	✓	✓	✕
Preferred Emission-Based	✓	✓	✕	✓
Pure Output-Based	✓	✕	✓	✓
Preferred Output-Based	✓	✓	✕	✓
Pure Auction	✕	✕ [b]	✓	✓
Preferred Auction	✓	✓	✕	✓

[a] Emission-based allocation does not produce a transfer to producers for customers of fully-resourced vertically-integrated utilities.

[b] The degree of transfer among retail provider customers would depend on the distribution of the auction revenues.

The pure emission-based allocation of allowances to deliverers would perform well for two of the evaluation criteria. The primary strike against a pure emission-based method is the risk of large windfall profits at the expense of most of the electricity customers in California served by IOUs, ESPs, and some POUs. An additional concern is that new entrants in electricity markets would be disadvantaged compared to deliverers that had been granted a perpetual allocation of allowances. These two concerns are both addressed in the version recommended by staff in which only half of the allowances would be granted on a historical emission basis with the rest distributed by auction or on an output basis, coupled with a rapid decline in the share of allowances allocated on a historical emission basis.

Both output-based methods would perform well in terms of holding down consumer cost. Any output-based approach with frequent updating also accommodates new entrants. The pure output-based approach differs significantly from the preferred approach with respect to transfers among the customers of different retail providers. While the pure output-based approach might result in significant transfers from the customers of coal-dependent retail providers in first year of the program, the preferred fuel-differentiated approach would produce virtually no transfers at the start of the program.

The evaluation of the pure auction approach with regard to consumer cost and transfers among customers of different retail providers is difficult without specifying what happens to the revenues from sale of the allowances at auction. If auction revenues in the pure auction approach were not used to mitigate consumer costs, auctioning would obviously have significant negative impacts on rates. Whether a large degree of transfer among customers of retail providers would occur, depends on how auction revenues would be used. The pure auction approach is the most administratively simple of all the methods examined. In the recommended auction approach, auction revenues would be distributed to retail providers on behalf of customers – initially on a historical emission basis and transitioning over time to a greater share allocated on a sales basis. This approach would reduce customer cost and mitigate the concern of transfers among customers of different retail providers but at the expense of increasing administrative complexity. The preferred auction option would also readily accommodate new entrants.

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